TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 95OPLR073
Significant Modification #1
to be issued to:

Colorado State University (CSU)
Larimer County
Source ID 0690011

Prepared on November 8, 1999
Revised on January 13, 2000
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Revised May and June 2000
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I. <u>Purpose</u>

This document will establish the basis for decisions made regarding the significant modification to operating permit 95OPLR073. It is designed for reference during review of the proposed permit by the source and other interested parties. This modification is based on several months of discussion and correspondence between Colorado State University (CSU) and the Division regarding potential errors in the issued operating permit. These discussions resulted in the submittal of operating permit application forms received on September 27, 1999. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

On April 16, 1998, the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction permits. These procedures are being directly implemented in all operating permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/throughput limits that appeared in the construction permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling 12 month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting hours of operation.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised Construction Permit.

II. Source Description

This source is a major university classified under Standard Industrial Classification (SIC) 8221. As a university, many varied activities take place on several campuses. However, only the heating plant on the main campus and incinerator units at the Center for Disease Control (CDC) and Animal Disease Laboratory (ADL) warrant permitting. The heating plant is on the main campus, located at University Avenue and Mason Street. The CDC and ADL are located at the Foothills Campus just off of Rampart Road. The city of Fort Collins is in an area designated as non-attainment for Carbon Monoxide. Wyoming is an affected state within 50 miles of the facility. Two Federal Class I wilderness areas, Rocky Mountain National Park and Rawah Wilderness Area, are located within 100 kilometers of CSU.

When the Operating Permit was initially issued, this facility was permitted as a synthetic minor source for purposes of Prevention of Significant Deterioration (PSD) (potential to emit limited to less than 250 tpy) with respect to NO_X, SO_X, VOC, PM and PM_{10}. The synthetic minor status was thought to be needed to avoid PSD issues surrounding the installation of boiler #1 in 1984. The synthetic minor source status was arrived at by placing emission limits on boilers # 2 and #3 which were previously grandfathered from Construction Permit requirements.

It should be clarified that the primary SIC code used for PSD determinations of this facility would be that of a major university. Since a university, as a whole, is not one of the 28 listed source categories it would be considered major for PSD at 250 tpy. Current guidance indicates that the intent of the PSD regulations was not to allow a listed source to avoid PSD review simply because it was part of an unlisted source. The university contains one of the 28 listed sources (fossil fuel fired boilers, or combinations thereof, totaling more than 250 MMBtu/hr heat input) which would be considered major for PSD at 100 tpy. This means that although the university itself will be considered major for PSD at 250 tpy, the main boilers shall be considered major for PSD at 100 tpy.

Since the existing emission limits for the boilers in the Operating Permit are well above 100 tpy, the synthetic minor status was not achievable. The issue is then whether the addition of boiler #1 in 1984 constituted a major modification, thus triggering PSD review. A reexamination of the source’s history revealed that the source could have used the emissions from the two old boilers replaced by boiler #1 for netting and could have shown a net emission increase below significance levels, thereby avoiding PSD review in 1984. The source submitted historical actual fuel use data from 1982 thru 1984 for the two old boilers; this fuel data was used to determine an average annual emission rate for the old boilers. Subtracting this average emission rate from the potential to emit of boiler #1 (using the fuel limit from the Construction Permit) shows that there were no net increases in criteria pollutant emissions that were above the PSD significance levels (see table below). It should be noted that all emission calculations were done using the most current emission factors from AP-42 and all assumptions were made to provide the most conservative results.

	New Boiler Emissions	**1982-84 Avg. Emissions**	**Net Change**
NOx	51.88	13.35	38.53
SO2	51.34	12.28	39.06
CO	13.52	8.95	4.57
VOC	0.98	0.61	0.37
PM	4.25	1.41	2.85
PM10	4.25	1.41	2.85

(See end of document for more detailed tables)

Since the facility could have netted out of PSD review using the emissions from the two old boilers alone without taking limits on boilers #2 and #3, it was determined that taking federally enforceable emission limits on boilers #2 and #3 was not necessary. Therefore, the grandfathered status of these two boilers has been reinstated and the boilers will be allowed to operate up to their potential to emit (8760 hrs/yr at design rate). The facility will now be considered a major stationary source for purposes of PSD review with respect to NO_X, SO_X, VOC, PM and PM_{10}.

Additionally, with the initial issuance of the operating permit, this facility was considered a minor source (potential to emit < 100 tpy) for purposes of nonattainment area major New Source Review (NSR) but will now be regarded as a major stationary source (potential to emit > 100 tpy) for purposes of nonattainment New Source Review (NSR) for Carbon Monoxide (CO). Again, since the CO emissions contribution from the insignificant activities is large, it is not possible for the source to operate below the 100 tpy threshold. Boilers #2 and #3 and the insignificant activities are all considered “grandfathered” from nonattainment area major NSR review and modifications up to this time, including the installation of boiler #1 in 1984, have not resulted in a net emissions increase above the CO significance levels (100 tpy). Any future modifications that result in a net emissions increase above 100 tpy of CO will trigger nonattainment area major NSR review.

The result of all of the above changes will result in an increase in apparent potential to emit (PTE) versus the issued Operating Permit. Revised PTE emissions for boilers #1, #2, and #3 are as follows:

Pollutant	**PTE (tpy)**
NO_x	355.2
SO_x	73.3

Pollutant	PTE (tpy)
CO	129.5
VOC	8.5
PM	18.3
PM_{10}	10.4

The PTE estimate does not include the 82 insignificant or exempt boilers/heaters and 19 insignificant/exempt generators. The above estimate is for the main boilers only and was determined as follows. The PTE of boiler #1 is the permitted emissions limits. The PTE for boilers #2 and #3 were calculated based on the maximum hourly fuel consumption rates provided in the operating permit application, a sulfur content of 0.05 wt % and AP-42 emission factors. Note that for boilers #2 and #3 the PTE was not determined using the Reg 1 emission limits for SO_2 (fuel oil only) and PM, as AP-42 emission factors do not indicate that these limitations would be exceeded based on the maximum expected sulfur content of the fuel oil (per operating permit application forms) and reasonably expected values for heat content. The PTE estimate reflected in the table is based on boilers #2 and #3 fired all on gas for NO_X, CO and VOC and Boilers #2 and #3 fired all on oil for SO_X, PM and PM_{10}. Note that with this modification CSU will discontinue use of No. 6 fuel oil as a back-up. The potential to emit, when burning fuel oil, is based on burning No. 2 fuel oil. It should also be noted that historic fuel use information indicates that CSU's actual emissions are generally well below the PTE values identified in the table.

III. Modification

A. S001: Babcock & Wilcox, Model FM 2990, S/N: BW-24790, 181 MMBTU/hr Boiler #1 - Natural Gas or Fuel Oil Use

1. Applicable Requirements - The applicable requirements that were in place in the original Operating permit will continue with the following revised emission and fuel limits: consumption of natural gas shall not exceed 550 MMscf per year; consumption of No. 2 fuel oil shall not exceed 275,000 gallons per year; emissions of air pollutants from the boiler shall not exceed 80.3 tons per year of Nitrogen Oxides (NO_X), 23.8 tons per year of Carbon Monoxide (CO), 1.5 tons per year of Volatile Organic Compounds (VOC), 15.6 tons per year of Sulfur Dioxide (SO_2), 2.5 tons per year of Particulate Matter (PM) and 2.5 tons per year of Particulate Matter less than 10 micron (PM_{10}). Also, CSU has discontinued the use of No. 6 fuel oil as backup fuel. The university will now use No. 2 fuel oil exclusively as a backup fuel.

As stated in the technical review document for the original permit issuance, since this boiler commenced construction after January 30, 1979 it is subject to the state-only requirements in Colorado Regulation No. 6, Part B, Section II (state-only NSPS for fuel burning equipment). Sources subject to any of the Reg 6, Part B requirements are also subject to the requirements in 40 CFR Part 60 Subpart A (NSPS general provisions), since they have been adopted by reference in Colorado Regulation No. 6, Part B, Section I.A. Although the specific requirements in Reg 6, Part B, Section II were streamlined out of the operating permit (see discussion on streamlining below), the NSPS general provisions still apply. It has been Division policy to include the NSPS general provisions in the operating permit for sources subject to NSPS requirements. Therefore, the Division will include the NSPS general provisions in the operating permit for Boiler No. 1. Typically, the only requirements the Division usually identifies and includes as NSPS general provisions are the good practices requirements and the circumvention requirement (40 CFR Part 60 Subpart A § 60.12, as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A), other general provisions, if they apply, may be included under the more specific requirements under which they apply (i.e. continuous emission monitoring, performance testing, opacity).

CSU submitted documentation showing that the university had a legally binding contract to construct the boilers in place prior to the June 19, 1984 applicability date for 40 CFR 60 Subpart Db. Since the definition of “commenced” in 40 CFR 60 Subpart A § 60.2 includes entering into a contractual obligation to undertake and complete a construction project, therefore, Subpart Db has not been included in the Operating Permit as an applicable requirement. CSU requested that the requirements in 40 CFR Part 60 Subpart Db be added to the permit shield for non-applicable requirements for Boiler No. 1.

Streamlining of Applicable Requirements

Based on the processing of other permits, the Division has added a section to Section III (permit shield) of the operating permit for requirements that had been streamlined. The technical review document for the initial issuance of the operating permit indicated that certain applicable requirements had been streamlined out of the operating permit. These requirements will be included in Section III.3 of the permit. The following discussion identifies the reasons for streamlining these requirements.

Opacity

This unit is subject to several opacity requirements. This unit is subject to the Reg 1 20% opacity requirement (Reg 1, Section II.A.1), the Reg 1 30% opacity requirement (Reg 1, Section II.A.4) and the state-only Reg 6, Part B 20% opacity requirement (Reg 6, Part B, Section II.C.3.a).

The Reg 1 20% requirement applies at all times, except when the Reg 1 30% opacity requirement applies which is during fire building, soot blowing, cleaning of fireboxes, startup, process modification or occasional cleaning or adjustment of control equipment. The Division believes that all of the special conditions identified under the Reg 1 30% opacity requirement are not applicable to the boilers at CSU. Fire building, soot blowing and cleaning of fireboxes are activities which this reviewer believes are only applicable to coal-fired boilers or boilers firing heavier/dirtier fuel oils. The CSU boilers do not have any control devices (i.e. baghouse or ESP) and therefore the occasional cleaning or adjustment of control devices are conditions that are not applicable to the CSU boilers. Finally, neither Reg 1, the Common Provisions Regulation or Reg 3 define a “process modification”. Generally a process modification for a boiler may be considered a load change, a change in fuel or a change air distribution. Although it is very likely that a fuel change could occur while the boiler is operating, this reviewer believes that with the fuels the source is using, a fuel change should not result in a large change in opacity that lasts for an extended period. Therefore, the special condition for process modifications do not apply to these units.

The state-only Reg 6 Part B opacity requirement applies at all times except during startup, shutdown and malfunction in accordance with the provisions in 40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference into Reg 6, Part B, Section I.A [exempts sources from opacity during startup, shutdown and malfunction].

The state-only Reg 6, Part B opacity requirements are less stringent than the Reg 1 (30% special conditions, 20% all other times) opacity requirements during startup, shutdown and malfunction. Therefore, the Reg 6, Part B opacity requirement will be streamlined out of the permit.

PM

This unit is subject to the Reg 1 particulate matter standards (Reg 1, Section III.A.1.b) and the state-only Reg 6 particulate matter standards for new fuel burning equipment (Reg 6, Part B, Section II.C.2). The Reg 1 and Reg 6, Part B particulate matter standards are the same. Therefore, the Division streamlined the Reg 6, Part B particulate matter standards out of the operating permit in favor of the Reg 1 particulate matter standards.

SO_2

This unit is subject to the Reg 1 sulfur dioxide standards (Reg 1, Section VI.B.4.b.(i)) and the state-only Reg 6 sulfur dioxide standards for new fuel burning equipment (Reg 6, Part B, Section II.D.2.a). The Reg 1 and Reg 6, Part B sulfur dioxide standards are the same. Therefore, the Division streamlined the Reg 6, Part B sulfur dioxide standards out of the operating permit in favor of the Reg 1 sulfur dioxide standards.

2. Emissions Factors - The emissions from the boiler are generated from the combustion of natural gas, fuel oil (#2), or a combination of both. The pollutants of concern when burning natural gas are NO_X and CO. Fuel oil combustion typically results in higher emissions of SO_2 and particulate matter (PM and PM_{10}). The source elected to use the emission factors published in the most recent revisions to AP-42 as representative of its boiler. The emission factors used are:

Pollutant	Fuel Oil (No. 2) (lbs/1000 gal)	Natural Gas (lbs/MMscf)
NO_X	24.0	280.0
SO_X	Material Balance	0.6
VOC	0.2	5.5
CO	5.0	84.0
PM_{10}	1	1.9
PM	2	1.9

(S) weight percent sulfur in the fuel oil in percent, not decimal value

Note that for calculating SO_2 emissions and demonstrating compliance with the Reg 1 SO_2 standards, when burning No. 2 fuel oil, the source has indicated that they will do a material balance and assume all sulfur exits the stack as SO_2.

3. Monitoring Plan - The existing permit identifies No. 6 fuel oil as the backup fuel. With these modifications, the source has indicated that they are discontinuing use of the No. 6 fuel oil and will use No. 2 fuel oil as the backup fuel. As a result of this fuel switch, the source will no longer be required to perform calculations to monitor compliance with the particulate matter requirements when burning fuel oil. When burning fuel oil, the source will now be required, at their request, to calculate SO_2 emissions and monitor compliance with the Reg 1 SO_2 standards using a material balance approach. The fuel oil sampling requirements have changed. In the existing permit, the source was required to sample the tank after a shipment, however, a sample of the tank contents was to be sampled. For the modification, the Division is only requiring the source to sample, or use vendor data for, each shipment of oil, not the mixture of oil in the tank. In the existing permit, a condition for substituting No. 2 fuel oil for No. 6 fuel has been removed from the permit, since only No. 2 fuel oil will be used in the future as a backup fuel. Finally, opacity monitoring for the 20% opacity requirement, when burning No. 2 fuel oil, has been changed. The modified permit requires that a Method 9 reading be taken 24 hours after completion of startup, once per quarter. If startup with fuel oil does not occur during a quarter, an opacity reading is not required. In addition, if fuel oil is burned continuously for 7 days, a Method 9 reading must be conducted on the 7^{th} day and every 7 days thereafter, when fuel oil is burned continuously.

4. Compliance Status - The source is currently undergoing negotiations with the Division for violations stemming from an annual inspection of the facility performed on July 21, 1999. It is expected that the facility will be able to demonstrate compliance upon issuance of the revised Operating Permit.

B. S002: Boiler #2 - Babcock & Wilcox, Model PFI-3063, S/N: BW-22213, 181 MMBTU/hr, Natural Gas or Fuel Oil Use
S003: Boiler #3 - Union Iron Works, Model 90460, S/N: UIW-7042, 88 MMBTU/hr, Natural Gas or Fuel Oil Use

1. Applicable Requirements - As discussed above these two boilers will once again be considered grandfathered from Construction Permit requirements, therefore the limits on emissions and fuel consumption have been removed. The source shall be required to track fuel consumption annually and to calculate emissions annually for fee and inventory purposes. Also the boilers will now burn No. 2 fuel oil for backup instead of No. 6 fuel oil. All other applicable requirements as listed in the original permit will remain in effect.

2. Emissions Factors - The emissions from the boilers are generated from the combustion of natural gas, fuel oil (#2), or a combination of both. The pollutants of concern when burning natural gas are NO_X and CO. Fuel oil combustion typically results in higher emissions of SO_2 and particulate matter (PM and PM_{10}). The source elected to use the emission factors published in the most recent revisions to AP-42 as representative of its boilers. The emission factors used are:

Pollutant	Fuel Oil (No. 2) (lbs/1000 gal)	Natural Gas (lbs/MMscf)
NOx	24.0 (S002) 20.0 (S003)	280.0 (S002) 100.0 (S003)
SO_x	Material Balance	0.6
VOC	0.2	5.5
CO	5.0	84.0
PM_{10}	3.3	7.6
PM	3.3	7.6

(S) weight percent sulfur in the fuel oil in percent, not decimal value

Note that for calculating SO_2 emissions and demonstrating compliance with the Reg 1 SO_2 standards, when burning No. 2 fuel oil, the source has indicated that they will do a material balance and assume all sulfur exits the stack as SO_2.

3. Monitoring Plan - See discussion of monitoring plan changes under Boiler # 1.

4. Compliance Status - The source is currently undergoing negotiations with the Division for violations stemming from an annual inspection of the facility performed on July 21, 1999. It is expected that the facility will be able to demonstrate compliance upon issuance of the revised Operating Permit.

C. Incinerators
S004: Shenandoah, Model P25-2GN-M1, S/N 868088, Biomedical Waste
S005: Therm-Tec, Model A-4-P, S/N: 4466, Pathological Waste

1. Applicable Requirements - These units are subject to the **state-only** requirements for Biomedical Incinerators in Reg. 6, Part B, Section V. In the operating permit application submitted in November 20, 1995 (for the existing permit), the design rate of unit S004 (CDC incinerator) was indicated as 100 lbs/hr and the design rate of the unit

S005 (ADL incinerator) was indicated to be 250 lbs/hr. The requirements in Reg 6, Part B, Section V are based on incinerator size (< 200 lbs/hr, ≥ 200 lbs/hr and ≥ 1000 lbs/hr), so the CDC unit was permitted with the requirements for units < 200 lbs/hr and the ADL unit was permitted with the requirements for units ≥ 200 lbs/hr.

The Division received revised Title V permit application forms on September 27, 1999, which indicate that the actual design capacity of the incinerators is lower than previously reported. In the September 27, 1999 submittal the design rate of the ADL incinerator is 175 lbs/hr and the design rate of the CDC incinerator is 75 lbs/hr. Although the design rate of both units is under 200 lbs/hr, several requirements (PM and HCl emissions and retention time) in Colorado Regulation No. 6, Part B, Section V are based on the facility's total incinerator design capacity, which is over 200 lbs/hr. Recent stack testing performed on these units December 20, 1999 and January 20, 2000 indicate that these units cannot meet all the standards for units ≥ 200 lbs/hr, however, they do meet the standards for units < 200 lb/hr.

Reg 6, Part B, Section V.C.2 allows facilities with total incinerator design capacity less then 400 lbs/hr to take the limitations for facilities with total incinerator design capacity less than 200 lbs/hr, provided the incinerator(s) operation for less than six hours per day. However, based on the operation of the ADL incinerator, CSU determined that this option was not feasible to them. However, CSU was willing to limit the design capacity for the CDC incinerator. According to the manufacturer the actual design capacity of the CDC incinerator is 100 lbs/hr (600 lbs of animals can be burned in approximately 6 hrs). However, this unit was stack tested based on the permitted batch size of ~ 75 lbs/hr and testing lasted for 6 hours. Therefore, the CDC incinerator will be permitted at the stack test hourly rate which is 12.5 lbs/hr. By limiting the hourly rate of the CDC incinerator, the total incinerator design capacity is 187.5 lbs/hr and therefore CSU is subject to the limitations for facilities with a total design capacity < 200 lbs/hr.

The issued operating permit included PM and HCl emission limits and retention time applicable to units ≥ 200 lbs/hr for the ADL unit. Therefore, the permit will be modified to include the requirements for units < 200 lbs/hr for the ADL incinerator, which are as follows:

- PM emissions shall not exceed 0.08 grains/dry standard cubic foot, corrected to 7% O_2, including condensibles (Reg 6, Part B, Section V.C.1.a.(3)).
- HCl emissions shall not exceed 4 lbs/hr **OR** achieve a 90% reduction, by weight, on an hourly basis (Reg 6, Part B, Section V.C.1.b.(2)(a) & (b)).
- Incinerator shall be equipped with a secondary combustion chamber or zone which provides for turbulent mixing and one (2) seconds of residence time at 1800 ° F or greater (Reg 6, Part B, Section V.D.1.b).

In the issued operating permit, requirements had been included for specific timer settings (Conditions 4.8 and 5.8) for both the CDC and ADL incinerators. The timer settings for the ADL unit were included in the operating permit by error, since the ADL unit did not have any timer settings specified in its construction permit (93LR1279I). The construction permit for the CDC incinerator (91LR693) contained a condition that specified the timer settings. It is not clear why the timer settings were included in the construction permit, however, they may have been included, in lieu of the stack testing requirement. Since a stack testing requirement was included in the operating permit and since there are specific requirements regarding the operation of the unit in Reg 6, Part B, Section V, which were included in the construction permit and also the operating permit, the Division believes it is unnecessary to include the time settings in the operating permit and they are being removed with this modification.

In the issued operating permit, the reporting requirements in Reg 6, Part B, Section V.G.2 were not included in the operating permit. This requirement is for the quarterly submittal of continuous emission/operating data gathered from the monitors. These incinerators are only required to continuously record the temperature of the gases leaving the primary and secondary combustion chambers. After, discussing this requirement with the Compliance, Monitoring and Enforcement Unit, the Division has determined that this data does not need to be submitted to the Division quarterly, however, this data must be made available to the Division upon request. This will be reflected in the modified operating permit.

The construction permit (91LR693) for the CDC unit contained the good practices requirement (condition 12) from the NSPS general provisions (40 CFR Part 60 Subpart A § 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A) and this requirement was not included in the issued operating permit. It has been Division policy to include the NSPS general provisions in the operating permit for sources subject to NSPS requirements. Therefore, the Division will include the NSPS general provisions in the operating permit for the CDC and the ADL incinerators. Typically, the only requirements the Division usually identifies and includes as NSPS general provisions are the good practices requirements and the circumvention requirement (40 CFR Part 60 Subpart A § 60.12, as adopted by reference in Colorado Regulation No. 6, Part B, Section I.A), other general provisions, if they apply, may be included under the more specific requirements under which they apply (i.e. continuous emission monitoring, performance testing, opacity monitoring).

The facility has also submitted notification, as required under 40 CFR 60.32e, as to how it intends to comply with the recently promulgated Hospital/Medical/Infectious Waste Incinerator emission guidelines. CSU has stated, in a letter dated November 29, 1999, that they will limit the types of waste burned in both incinerators to those meeting the definition of “pathological waste” as defined in 40 CFR 60.51c. By combusting only these types of waste, the University will be exempted from the emissions control requirements of Subpart Ce. The requirement to burn pathological waste only, as defined in 40 CFR 60.51c shall be included in the permit as an applicable requirement. Note that this requirement supercedes the requirements in the construction permits for burning only biomedical waste, of which pathological waste is a subset of, for the CDC unit (91LR693) or pathological waste with a heating value of 1000 Btu/lb for the ADL unit (93LR1279I).

The original technical review document, which was prepared to support the issued operating permit, indicated that these units were also subject to the requirements of Reg 6, Part B, Section VII (general incinerator requirements) and that these requirements were less stringent than the requirements for biomedical waste incinerators (Reg 6, Part B, Section V) and therefore were not included in the operating permit. While it is true that the general incinerator standards are less stringent than the biomedical waste incinerator standards, the general incinerator standards do not apply to incinerators that are subject to the biomedical incinerator standards, per Reg 6, Part B, Section VII.A.

Note that both construction permits 91LR693 (CDC unit) and 93LR1279I (ADL unit) included requirements for odor (Reg 2), this condition is included in the operating permit in Section IV (general conditions), No. 13 and therefore will not be included as a specific applicable requirement for the incinerators in Section III of the permit. Reg 6, Part B, Section V.G.3 and Colorado Construction Permit 91LR693, condition 11 (CDC incinerator) identifies the upset requirements that are also found in the Common Provisions Regulation, Section II.E. With this modification, the upset conditions will be included in Section IV (general conditions), No. 4 of the permit and therefore, these requirements will not be included as a specific condition for the incinerators in Section III of the permit for these units.

Streamlining of Applicable Requirements

<u>Opacity</u>

These units are subject to several opacity requirements. These units are subject to the Reg 1 20% opacity requirement (Reg 1, Section II.A.1), the Reg 1 30% opacity requirement (Reg 1, Section II.A.4) and the state-only Reg 6, Part B 10% opacity requirement (Reg 6, Part B, Section V.C.1.d).

The Reg 1 20% requirement applies at all times, except when the Reg 1 30% opacity requirement applies which is during fire building, soot blowing, cleaning of fireboxes, startup, process modification or occasional cleaning or adjustment of control equipment. The Division believes that all of the special conditions identified under the Reg 1 30% opacity requirement are not applicable to these incinerators. Fire building, soot blowing and cleaning of fireboxes are activities which this reviewer believes are only applicable to coal-fired boilers or boilers firing heavy fuel oils (i.e. fuel oil No. 6). These incinerators do not have any control devices (i.e. baghouse or ESP) and therefore the occasional cleaning or adjustment of control devices are conditions that are not applicable to these units. Finally, neither Reg 1, the Common Provisions Regulation or Reg 3 define a "process modification". These incinerators operate in batch mode and these units are required to have interlocks to prevent waste from being charged until the optimum temperature is reached at the exit of the secondary combustion chamber and combustion is complete. In addition, the primary and secondary combustion chambers are required to be able to maintain the required combustion temperatures without the assistance of the waste burned by means of air/fuel automatic modulating controls. This reviewer believes that the required design of these units, prevent process modifications from being made, while waste incineration is occurring. Therefore, this reviewer believes that the only special condition under which the 30% opacity requirement applies is during startup.

The state-only Reg 6 Part B 10% opacity requirement applies at all times except during startup, shutdown and malfunction in accordance with the provisions in 40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference into Reg 6, Part B, Section I.A [exempts sources from opacity during startup, shutdown and malfunction]. The Reg 1 opacity requirements (30% startup, 20% all other times) are more stringent that the Reg 6 Part B opacity requirement under conditions of startup, shutdown and malfunction and the Reg 6, Part B opacity requirements are more stringent during normal operations (see attached grid). Therefore, no opacity requirements can be streamlined out of the operating permit.

Note that since waste cannot be charged in the incinerator until the temperature of the combustion chamber reaches 1800 ° F and that the secondary combustion chamber must remain at 1800 ° F until the waste is completely combusted, this reviewer believes that startup and shutdown occur prior to burning waste and after complete combustion of the waste. Therefore, startup and shutdown involve only natural gas combustion.

<u>General</u>

There are some general requirements that were found in either the construction permits or in Reg 6, Part B, Section V that were also streamlined out of the operating permit. Specifically, permits 93LR1279I (ADL unit) and 91LR693 (CDC unit) and Reg 6, Part B, Section V.G.1 requires that monthly summary files of daily burning rates and hours of operation be maintained and requires that these files be kept for two years.   For sources subject to operating permit requirements, records used for compliance monitoring shall be kept on site for five years, as indicated in Section IV (general conditions) No. 21.b of the operating permit. Therefore, the requirement to retain records for 2 years will be streamlined out in favor of the five year requirement.

Secondly, permit 93LR1279I, condition 4 states that the charging door shall not be opened during firing cycle so as not to disturb the combustion cycle. Reg 6, Part B, Section V.D.3 requires that batch units be equipped with a lock-out mechanism to prevent charging after startup. The Reg 6, Part B requirement is more stringent than the requirement in the construction permit, therefore, the construction permit requirement will be streamlined out of the permit in favor of the Reg 6, Part B requirement.

2. Emissions Factors - Calculation of emissions was not included in the original Operating Permit and will not be added to the revision.

3. Monitoring Plan - No significant changes were made to the monitoring plans for these emission units.

4. Compliance Status - The source is currently undergoing negotiations with the Division for violations stemming from an annual inspection of the facility. It is expected that the facility will be able to demonstrate compliance upon issuance of the revised Operating Permit.

D. S006: Four (4) 30,000 Gallon No. 2 Fuel Oil Storage Tanks

1. Applicable Requirements - The existing fuel storage tanks were replaced when the University elected to switch to the use of No. 2 fuel oil as a backup fuel. The emissions from these tanks are below de minimis levels and would normally be exempt from APEN and permitting requirements. However, since Regulation 3, Part A, Section II.D.4, states that a source may not take an APEN exemption that would allow a source to avoid a specific federal or state applicable requirement the storage tanks must be included in the Operating Permit. Since the tanks were constructed after the applicability date of NSPS Subpart Kb, they are subject this regulation. However, since the tanks meet the capacity and stored liquid criteria contained in 40 CFR 60.110b(c), the tanks are only required to meet the requirements of 40 CFR Part 60 Subpart Kb §§ 60.116b(a) & (b).

40 CFR 60.116b(b) requires that the source maintain “readily accessible” records showing the dimensions of the tank and an analysis showing the capacity of the storage vessel. 40 CFR Part 60 Subpart Kb § 60.116b(a) requires that these records be kept for the life of the tanks.

The only other applicable requirement for the storage tanks is APEN reporting per Colorado Regulation No. 3, Part A, Section II.

2. Emissions Factors - Emission from storage tanks may be estimated using the EPA model called Tanks. However, since the emissions from the storage tanks are virtually zero, no emission calculations shall be required.

3. Monitoring Plan - The only monitoring requirement for these tanks will be to maintain the proper records pursuant to 40 CFR Part 60 Subpart Kb §§ 60.116b(a) & (b).

4. Compliance Status - The source is believed to be in compliance with the applicable requirements for this point.

IV. <u>Accidental Release Prevention Program 112(r)</u>

This source indicated in its original application that it was subject to the provisions of 112(r) of the federal Clean Air Act. This was because of propane storage at CSU. However, since propane has been removed from the list of materials, these requirements are no longer applicable to the facility. As such, the provisions of 112(r) will be removed from the permit.

V. <u>Conclusions</u>

Following issuance of the operating permit, the source indicated that the permit may have several errors. The source elected to request this modification in order to correct these potential errors in the original permit and to allow more operational flexibility. The source should be able to meet the emission limits in the revised Operating Permit and no additional testing requirement will be necessary.

Historical Actual Fuel Use

		Total Consumption, All Boilers			Consumption, #1 & #2		
		Nat. Gas (ccf)	Fuel Oil (Gallons)	MMBTU	Nat. Gas (ccf)	Fuel Oil (Gallons)	MMBTU
1982	**November**	962463		85659	251202.84	0	22356.999
	December	998966		88908	260730.13	0	23204.988
1983	**January**	934578		83177	243924.86	0	21709.197
	February	853851		75993	222855.11	0	19834.173
	March	883329		78616	230548.87	0	20518.776
	April	111502	365725	64782	29102.022	95454.225	16908.102
	May	17464	287725	44717	4558.104	75096.225	11671.137
	June	36715	184550	30950	9582.615	48167.55	8077.95
	July	488137		43444	127403.76	0	11338.884
	August	499527		44458	130376.55	0	11603.538
	September	460633		40996	120225.21	0	10699.956
	October	604738		53822	157836.62	0	14047.542
First Year Total:		**6851903**	**838000**	**735522**	**1788346.7**	**218718**	**191971.24**
	November	927026		82505	241953.79	0	21533.805
	December	1288002		114632	336168.52	0	29918.952
1984	**January**	1135088		101023	296257.97	0	26367.003
	February	957074		85180	249796.31	0	22231.98
	March	912697		81230	238213.92	0	21201.03
	April	793807		70649	207183.63	0	18439.389
	May	429750		38248	112164.75	0	9982.728
	June	365405	3113	32988	95370.705	812.493	8609.868
	July	479035		42634	125028.14	0	11127.474
	August	455405		40531	118860.71	0	10578.591
	September	484707		43139	126508.53	0	11259.279
	October	747667		66542	195141.09	0	17367.462
Second Year Total:		**8975663**	**3113**	**799301**	**2342648**	**812.493**	**208617.56**

Emissions from old Boilers #1 & #2 (tpy)

	1982-83			1983-84			
	Gas	Oil	Total	Gas	Oil	Total	Average
NOx	8.94173	6.0147	**14.96**	11.713	0.022	**11.74**	**13.35**
SO2*	0.0537	24.343	**24.40**	0.07	0.09	**0.16**	**12.28**
CO	7.51106	0.5468	**8.06**	9.8391	0	**9.84**	**8.95**
VOC	0.4918	0.083	**0.57**	0.6442	0	**0.64**	**0.61**
PM	0.67957	1.2358	**1.92**	0.8902	0	**0.89**	**1.41**
PM10	0.67957	1.2358	**1.92**	0.8902	0	**0.89**	**1.41**

Emission Factors (<100 MMBTU/hr Boiler)

	Gas (lb/MMscf)	No. 6 Oil (lb/kgal)
NOx	100	55
S02*	0.6	222.6*
CO	84	5
VOC	5.5	0.76
PM	7.6	11.3
PM10	7.6	11.3

(from AP-42 Sect 1.3, 9/98 & 1.4, 3/98)

* Maximum sulfur content allowed under Reg. 1 assumed

Net Increase (tpy)

	Using Fuel from 85LR251 †			1982-84 Average Total	
	Gas	Oil	Total	Total	Net Change
NOx	41.3	10.575	**51.88**	**13.35**	**38.53**
SO2*	0.0885	51.255	**51.34**	**12.28**	**39.06**
CO	12.39	1.125	**13.52**	**8.95**	**4.57**
VOC	0.81125	0.171	**0.98**	**0.61**	**0.37**
PM	1.121	3.1298	**4.25**	**1.41**	**2.85**
PM10	1.121	3.1298	**4.25**	**1.41**	**2.85**

Emission Factors (181 MMBTU/hr Boiler)

	Gas (lb/MMscf)	No. 6 Oil (lb/kgal)
NOx	280	47
S02*	0.6	227.8
CO	84	5
VOC	5.5	0.76
PM	7.6	13.91
PM10	7.6	13.91

(from AP-42 Sect 1.3, 9/98 & 1.4, 3/98)

† 295 MMscf Nat. Gas & 450 kgal No. 6. No specific limit on F.O. - used for curtailment periods only. Maximum allowable sulfur content per Reg. 1 assumed.